ILLINOIS COMMERCE COMMISSION

DOCKET NO. 01-0432

EXHIBITS SPONSORED BY DANIEL L. MORTLAND

November 14, 2001

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ILLINOIS COMMERCE COMMISSION

DOCKET NO. 01-0432

PREPARED SURREBUTTAL TESTIMONY OF

DANIEL L. MORTLAND

I. WITNESS INTRODUCTION

1. Q. Please state your name, business address and present position.

A. My name is Daniel L. Mortland, 500 South 27th Street, Decatur, Illinois 62521. I am Director of Regulated Pricing and Costing Services for Illinois Power Company ("Illinois Power", "IP" or "Company").

2. Q. Have you previously submitted testimony and exhibits in this proceeding?

A. Yes, I have submitted direct, supplemental and rebuttal testimony in this proceeding. My direct testimony and exhibits were submitted as IP Exhibits 3.1 through 3.9. My supplemental testimony was IP Exhibit 3.10 and was accompanied by Corrected Revised Exhibits 3.2 through 3.9. My rebuttal testimony and exhibits were submitted as IP Exhibits 3.11 through 3.16.

3. Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is two-fold. First, I will respond to certain issues in the rebuttal testimonies of Staff witnesses Langfeldt and Schlaf, MidAmerican witness Phillips and IIEC witness Gorman. Second, I will present the Company's revised revenue requirement for electric distribution based on Staff and intervenor adjustments accepted by the Company and revisions and updates to other data, as detailed in my surrebuttal testimony and that of other IP witnesses.

4. Q. In addition to your prepared surrebuttal testimony, IP Exhibit 3.17, are you sponsoring other exhibits?

A. Yes, I am sponsoring IP Exhibits 3.18 through 3.25, which were prepared under my supervision and direction.

II. Cost of Capital

5. Q. What cost of capital is the Company proposing?

A. IP is proposing an overall cost of capital of 8.92%. IP Exhibit 3.18 shows the weighted average cost of capital based on the Company's surrebuttal position as to capital structure and the cost rates for the various classes of capital, including a rate of return on common equity of 12.50%. The proposed overall cost of capital of 8.92% is lower than the cost of capital of 9.17% at June 30, 2001, that I proposed in my rebuttal testimony.

6. Q. Are you proposing any changes to the balances and cost rates for preferred stock and preferred securities?

A. Yes. As shown on IP Exhibit 3.19, I am updating the balances of preferred securities to reflect amortization from June 30, 2001, to August 31, 2001. The balance of preferred securities at August 31, 2001, is the same as that shown on corrected revised IP Exhibit 3.6.

A. Response to Staff Witness Langfeldt

7. Q. Do you accept any of the changes to the calculation of IP's embedded cost of long-term debt that were proposed by Staff witness Rochelle Langfeldt?

A. I accept Ms. Langfeldt's proposal to use a 34.5 basis point spread above the interest rate of Aaa-rated municipal bonds as a proxy for the interest rate of IP's Aaa-rated variable-rate pollution control bonds. This spread accounts for the difference in Aaa-rated municipal bonds and IP's variable-rate pollution control bonds that I described in my rebuttal testimony. However, I disagree with Ms. Langfeldt's use of interest rates on municipal bonds from a single day as the basis to set the interest rate on IP's pollution control bonds for ratemaking purposes. Even though rates on the variable-rate pollution control bonds are re-set weekly, these are long-term securities. Furthermore, the rates set in this proceeding will be in effect for at least a year and probably longer.

For the reasons stated in my rebuttal testimony, I believe that Ms. Langfeldt's determination of the cost rate of Aaa-rated variable-rate pollution control bonds by using interest rate data at a single point in time is flawed. Using a single point in time can lead to faulty conclusions. Using an average over a recent historical period will tend to even out the fleeting effects that may drive interest rates on a day to day basis.

8. Q. How have you determined the interest cost for IP's variable-rate pollution control bonds?

A. I started with the average of the BMA Index for 2001 through August 2001, which is 3.00%. The BMA Index is published by the Bond Market Association and is a seven-day high grade market index of tax-exempt debt obligations taken from an extensive database. It is a widely-used benchmark for interest rates on short-term tax-exempt debt obligations. I then added 34.5 basis points which yields an overall cost rate for the variable-rate pollution control bonds of 3.35%. In my rebuttal testimony, I had used the actual rates for the individual variable-rate pollution control bond issues. Based on actual costs for 2001 through August, these actual rates have ranged from 3.75% to 4.00%.

9. Q. What is the Company's proposed embedded cost of long-term debt?

A. The embedded cost of long-term debt based on the changes I have made, and the changes proposed by Ms. Langfeldt that I have accepted, is 7.01% as of August 31, 2001, as shown on IP Exhibit 3.18, Line 1. This represented a reduction from the value of 7.31% presented in my rebuttal testimony. The primary reason for the reduction is the lower interest cost that I have developed for the pollution control bonds.

10. Q. What is the balance of IP's long-term debt that you are using to establish the capital structure?

A. The balance of long-term debt is $1,095,159,742, which reflects the actual balances on IP's books as of August 31, 2001, as shown on IP Exhibit 3.20.

11. Q. With respect to the cost rate for the Transitional Funding Instruments, have you removed the effects of loss on reacquired debt and issuance discount and expense from the IRR calculation and instead performed a straight-line amortization of these non-cash items as proposed by Staff witness Langfeldt?

A. Yes, I have, as shown on IP Exhibit 3.21.

12. Q. Do you agree with Staff witness Langfeldt's proposed change in the IRR methodology regarding whether to consider the compounding effect of the cost of the TFIs?

A. No. Ms. Langfeldt's method ignores the overall theory that is the basis of the IRR calculation. Her method will yield a faulty result since it does not consider that there actually is a compounding effect in determining the discount rate that makes the net cash flows related to the TFIs go to zero.

13. Q. What overall cost rate have you calculated for the TFIs?

A. I have calculated a rate of 7.08%. This rate was determined using a cash flow analysis on the cash items (i.e., principal and interest payments) and straight-line amortization of the non-cash items (i.e., debt discount, issuance expense and loss on reacquired debt). In using a straight-line amortization for the non-cash items, I am accepting one of the steps that Ms. Langfeldt has proposed. The resulting rate is 7.08% as shown on IP Exhibit 3.21. The cost rate of 7.08% for the TFIs is lower than the cost rate of 7.75% that I proposed in my rebuttal testimony.

14. Q. What balance of TFIs do you propose be used for determining the ratemaking capital structure?

A. I propose using the balance of $590,788,136, which is the remaining principal amount at August 31, 2001, less unamortized discount, issuance expense and loss on reacquired debt, as shown on IP Exhibit 3.21.

15. Q. What cost rate for short-term debt are you proposing?

A. I am proposing that IP's actual average cost of short-term debt for the month of August 2001 be used plus the cost of the back-up line of credit that supports IP's short-term debt. I continue to disagree with Ms. Langfeldt that the cost rate for short-term debt should be based on information from a single date, and therefore have used cost information for a one-month period. For my surrebuttal presentation, I have used interest rate information for the month of August 2001, rather than June 2001 as used in my rebuttal testimony. The August average cost of short-term debt was 3.85%. The back-up line of credit cost was 0.125%. Therefore, I propose that the cost of short-term debt be 3.98%. This cost rate is lower than the cost rate of 4.53% that I proposed in my rebuttal testimony.

16. Q. Are you proposing any changes to your rebuttal testimony regarding the balances of short-term debt less construction work in progress?

A. Yes. I am proposing that the balances be based on six months of actual balances and six months of projected results as proposed by Staff witness Langfeldt. Since I have used the balances of long-term debt, TFIs, preferred stock and preferred securities, and common equity, at August 31, 2001, I have developed the short-term debt balance using actual data for the six months ended August 31, 2001, and projected data for the six month period of September 2001 through February 2002. This calculation yields an average balance of $170,409,957, as shown on IP Exhibit 3.22.

17. Q. What is the balance of common stock equity?

A. The balance of common equity at August 31, 2001, is $1,186,425,920 as shown on IP Exhibit 3.23. The common equity ratio is 37.28%. The common equity ratio excluding consideration of short-term debt is 39.4%.

B. Response to IIEC Witness Gorman

18. Q. Do you have any comments on Mr. Gorman's rebuttal testimony regarding the impact of TFIs in IP's capital structure?

A. Mr. Gorman may not have fully understood the point I was trying to make in my rebuttal testimony. I know that the debt rating agencies do not consider IP's TFIs in determining IP's debt leverage for purposes of establishing the ratings on IP's debt. What I could not tell from the source documents Mr. Gorman had provided, and what I still cannot tell, is (1) whether the other companies included in the published rating agency capital structure data to which Mr. Gorman compared IP have issued securities similar to IP and (2) if they do, whether the rating agencies have similarly excluded those securities in determining debt leverage for the other companies. Therefore, it is not clear whether there is comparability between IP's debt leverage excluding TFI's and the industry data Mr. Gorman has used.

19. Q. What is your response to Mr. Gorman's assertions about rating agencies giving some consideration to purchased power obligations as debt?

A. Mr. Gorman references a credit report from November 1998 (page 3, lines 17-20 of his rebuttal testimony). Using a report from November 1998 does not provide conclusive proof of whether the rating agencies treat purchased power obligations as debt leverage when analyzing IP's credit-worthiness. IP did not sell its generation facilities to Dynegy Midwest Generation and AmerGen and begin purchasing power under the power purchase agreement with these entities until the fourth quarter of 1999. As shown in the attachment to the response to IIEC data request 15, Standard & Poor's specifically states "(S&P) would adjust the company's financial ratios to account for a power purchase buyback obligation relating to a Clinton sale."

20. Q. Do you agree with Mr. Gorman that there is no cost of service impact related to his disagreement with you?

A. No. The purpose of my comments concerning Mr. Gorman's rebuttal testimony was to take issue with his characterization of IP as having a 45% common equity ratio excluding TFIs for purposes of setting the cost of equity in this proceeding. I agree that debt rating agencies may ignore IP's TFIs and similar securities issued by other utilities when establishing debt ratings, but the presence of TFIs in IP's capital structure would be perceived as increasing IP's debt leverage and adding risk from the perspective of the common equity investor. An equity investor, being lower in priority than a debt investor, would be concerned that a portion of IP's allowed revenues are not in fact owned by IP but rather are owned by IP Special Purpose Trust and will go to service the TFIs. This leaves a lower amount of revenues to satisfy IP's other senior obligations and, ultimately, to flow through to the equity investor. Therefore, the equity investor would view the TFIs as debt leverage. Therefore, in setting the cost of common equity, IP must be viewed as having a

37% common equity ratio (i.e., including the TFIs) as shown on IP Exhibit 3.18, not as having a 45% common equity ratio. A utility with a 37% common equity ratio would be expected to have a higher cost of common equity than a utility with a 45% common equity ratio, all other things being equal.

III. Response to Staff Witness Schlaf and MidAmerican Witness Phillips

21. Q. What is the purpose of this section of your testimony?

A. In their rebuttal testimonies, Staff witness Eric Schlaf and MidAmerican witness George Phillips discuss the provisions originating in Illinois Power's Transitional Funding Order ("TFO"), Docket No. 98-0488, relating to the obligations of RES and other third-party collectors with respect to the collection of instrument funding charges ("IFC") from IP's retail delivery services customers and remittance of the IFC to IP. Both witnesses indicate confusion as to the intended coverage of these requirements. The purpose of my testimony is to describe the underlying credit risk that these provisions were intended to address, in order to assist in clarifying their coverage.

22. Q. Where are the provisions of the TFO that you are referring to located in the TFO?

A. The provisions that I am addressing are found at pages 17-19 and in Findings (54) through (56), and the related ordering paragraphs, of the TFO. There is also related discussion, describing IP's initial proposal in Docket No. 98-0488 on this topic, at pages 13-15 of the TFO.

23. Q. Are these provisions also embodied in IP's IFC tariff?

A. Yes, these provisions are included in Section V of IP's Rider IFC.

24. Q. Were you involved in obtaining the TFO and in the structuring of the issuance of the transitional funding instruments ("TFI") by Illinois Power Special Purpose Trust in December 1998?

A. Yes, I was.

25. Q. Who is the owner of the IFC revenues?

A. The IFC revenues are owned by Illinois Power Special Purpose Trust ("Trust"). Illinois Power acts as Servicer to bill and collect the IFCs from retail customers and to remit the IFCs to the Trustee, on Trust's behalf. Illinois Power's obligations as Servicer are largely governed by an Intangible Transition Property Servicing Agreement between IP and Illinois Power Securitization Limited Liability Company, whose rights are assigned to Trust. The IFCs that Illinois Power, as Servicer, bills to retail customers are not charges of Illinois Power but of Trust, and payment of the IFCs is owed by the customer to Trust, not to Illinois Power.

26. Q. What is the underlying credit risk that the provisions of the TFO relating to collection and remittance of IFCs by RESs and other third-party collectors are intended to address?

A. To answer that question, I need first to provide some background. The TFIs are AAA-rated. They are AAA-rated because they are regarded by the rating agencies as having an extremely high likelihood of both timely payment of principal and interest, and ultimate payment of principal and interest. These are two distinct concepts. A security that had a high likelihood of ultimate payment of principal and interest but some risk of untimely (i.e., delayed) payment of principal and interest would be regarded as a worse credit than a security with high probability of both ultimate payment and timely payment.

Principal and interest, as well as other administrative expenses associated with the TFIs, are paid by the Trust to the TFI holders each quarter using the IFCs that have been collected from customers by IP as Servicer, and remitted by IP to the Trust. Every six months, the per-kwh IFCs are re-set based on the amount of IFC collections that are needed over the ensuing six months to support payment of principal, interest and expenses for that period. This calculation takes into account the extent to which there have been overcollections or undercollections during the preceding six months. Overcollections during a particular six-month period are not simply "kept" by the Servicer or the Trustee to provide a cushion against possible future undercollections; rather, overcollections in a six-month period serve to reduce the level of the per-kwh IFCs that must be billed in the succeeding six-month period. Thus, although there are some reserves provided, the ability of the Trust to pay principal and interest to the TFI holders each quarter as scheduled -- that is, to make timely payment as well as ultimate payment -- is dependent on predictable levels of IFC collections.

At the time that the TFI issuance was being structured, in the latter part of 1998, Illinois Power was still providing only fully bundled electric service to its retail customers. One of the things the security rating agencies paid close attention to, in reaching the conclusion that the TFI could be rated AAA, was the quality of IP's systems and procedures for calculating and issuing customer bills, and collecting payments and posting them to customer accounts. Another thing the rating agencies carefully scrutinized was IP's historical data on both the timeliness of payment of bills by customers and the extent of non-payments by customers. Two factors that enabled the rating agencies to determine the TFIs could be AAA-rated were: (1) the quality and regularity of IP's systems and procedures for calculating and issuing customer bills, collecting payments and posting them to the appropriate customers' accounts, and pursuing collections from late-paying or non-paying customers; and (2) the facts (supported by historical data) that a high percentage of electric utility customers pay their bills on time and that a high (though lesser) percentage of electric customers ultimately pay their bills, even though some pay late. The extensive historical data available on the timeliness and ultimate certainty of bill payments by retail electric customers enabled the rating agencies to evaluate, with a good degree of predictability, the risk that there would be sufficient non-payment or late payment of IFCs by retail customers to threaten either the timeliness of the quarterly payment of principal and interest on the TFIs, or the ultimate certainty of payment.

At the time the TFI transaction was being structured and the TFIs were issued, IP provided only bundled electric service. However, it was envisioned with the advent of unbundling that RESs and other entities would become involved in transmitting bills for IP's services to customers and in collecting payments from customers and remitting those payments to IP. The fact that third parties would become involved in the billing and collection relationship between IP and the retail customer was of concern to the rating agencies because it introduced new, largely unknown risks into the analysis. By "largely unknown," I mean that in contrast to the large body of historical data available on the timeliness of individual customers' payment of their bills to IP, there was no comparable body of data or experience on the reliability and timeliness of third parties who in the future might either transmit IP's bills to the retail customer, or collect payments from the retail customer for remittance to IP. Specific areas in which additional risk was introduced were: (1) Bills would not be transmitted to customers only by IP, using its established systems and procedures that the rating agencies had had the opportunity to evaluate, but also by new entities whose systems and procedures were unknown. (2) There was the risk that although the customer made a timely payment to the third party, the third party might not make a timely remittance of the customer's payment to IP. (3) There was a risk that a third party could go into bankruptcy or otherwise default while holding payments from numerous customers. Such a bankruptcy or other default would at a minimum result in a delay in the ultimate remittance of IFC payments to IP and thus jeopardize the timeliness of payment of principal and interest to the TFI holders. These were materially different risks from the predictable likelihood that an individual customer would pay late, or fail to pay, its electric bill to Illinois Power.

Therefore, in order to obtain AAA ratings on the TFI, the rating agencies insisted on provisions being included in the transaction structure to minimize the likelihood of untimely remittance by third parties collecting payments by customers, including the risk of default by such a third party while holding multiple customer payments. These provisions included requiring that third parties that handled collection of customer payments and remittance to IP make the remittance of IFC collections to IP within specified time periods, and that such entities demonstrate acceptable levels of creditworthiness.

27. Q. Were the provisions that were included in IP's TFO developed by IP?

A. Not unilaterally. As the summary of the testimony at pages 13-15 of the TFO indicates, IP, based on discussions with the rating agencies, proposed different provisions than those ultimately included in the TFO. Commonwealth Edison ("ComEd"), which was also in the process of obtaining a TFO at about the same time in 1998, also proposed provisions addressed to this issue. Commission Staff and at least one potential RES that had intervened in the TFO cases had objections to the provisions proposed by IP and by ComEd. As a result, the provisions that ultimately appeared in the IP and ComEd TFOs were negotiated among these parties.

28. Q. Based on the history and purpose of these provisions as you have described, is there a relatively simple way to characterize what types of entities were intended to be covered by the third party collector provisions in the TFO?

A. Yes, I would say that the third party collector provisions were intended to apply to any entity that is in the business of, among other things, collecting payments of amounts billed for IP's tariffed electric services from retail customers and/or remitting collections or payments to IP on the customers' behalf.

29. Q. Why do you refer to any entity that is "in the business of" collecting payments for IP's services from customers and remitting the collections to IP?

A. I am intending to exclude persons or entities that may take care of seeing to payment of just one or two customers' bills, such as a friend or relative who takes responsibility for seeing to it that an elderly customer's electric bill is paid on time. In such situations, the third party is not handling the customer's payments for commercial purposes. Such situations do not appreciably change the risk that the individual customer will not pay the bill or will make an untimely payment. These situations do not present the risk that I described above of a third party going into bankruptcy or otherwise defaulting while holding multiple customer payments. In contrast, such an event could occur in the case of a company that has entered the business of acting as agent for retail customers in their dealings with utilities, and thus receives and remits payments from multiple customers in the aggregate.

I am also intending to exclude situations in which a customer has multiple locations and is requesting that the bills for all of those locations be sent to a single corporate office. For example, if IP has ten stores of a retail chain in its service area and they all request that their IP bills be sent to a single regional or corporate office of the company for processing and payment, IP would not view the regional or corporate office as a commercial entity in the business of collecting or remitting payments on behalf of other customers. In this situation, the retail chain store company is still the customer of record and is paying its own bills directly to IP.

30. Q. Do you agree with Dr. Schlaf and Mr. Phillips that how to apply the "third party collector" provisions of the TFO is confusing?

A. I believe that one could be confused if one focused solely on the words "being billed" and "collector" and does not consider the background that led to these provisions, but I do not believe that there should be confusion if one focuses on the entirety of these provisions and understands the background behind their development. The actual obligations that the TFO authorizes IP to impose on "third party collectors" relate to the functions of collection and remittance of payments, not to the function of transmitting the bill to customers. Therefore, as I have indicated above, the key to the application of these provisions should be whether another commercial entity is inserted into the process of remittance of payments from the retail customer to IP.

31. Q. But aren't there entities that undertake to remit customers' payments to the utility without also receiving the customer's bill and passing it on, in whatever form, to the customer?

A. Yes, and this is where the requirement that an entity must be receiving the bills for IP's services to the retail customer comes in. An entity could agree with a customer that the customer will continue to receive the bill directly from the utility but then will give the bill, and the funds for payment, to the entity for remittance to the utility. IP has no control over these situations in that all IP does is receive the payment from the entity – IP is not being asked to send the customer's bill to the entity. However, where IP is asked to send the customer's bill to another entity, then IP has the ability to require the entity to comply with the third party collector requirements. The TFO recognizes this. I should add that while situations exist in which an entity does not receive and transmit to the customer IP's billing information but does receive the customer's payment and remit it to IP, the reverse situation would seem highly unlikely (i.e. the entity receives and passes on IP's bill to the customer but is not involved in the remittance of payment from the customer to IP).

32. Q. MidAmerican witness Phillips states that the collection risk with regard to collection of IFCs from the customer does not change when an agent acts on behalf of a customer, because the customer is still ultimately liable for payment. Do you agree?

A. No, I do not agree. Even if the customer remains ultimately liable for payment to IP of monies that the customer has already given to the agent but the agent fails to remit to IP, there would certainly be some delay experienced in obtaining the second payment from the customer. This could jeopardize the sufficiency of IFC collections in a quarter to cover the scheduled payment of principal and interest on the TFIs, and thus jeopardize the timeliness of payment of principal and interest on the TFIs, which is an important factor in their AAA rating. Further, introduction of agents into the process additionally increases the risks of untimely payment or of non-payment to the extent that the agent is acting not just for one retail customer but rather for multiple IP retail customers, which I assume is part of MidAmerican's business objectives.

33. Q. Proposed Section 6(u) of IP's Standard Terms and Conditions as filed in this case states that "Any entity seeking to bill customers for utility service must sign an agreement provided by utility governing the remittance to utility of amounts owed by customers to utility, including IFC payments." Can you think of any revisions to this language that would make its intended coverage clearer?

A. Based on my review of Dr. Schlaf's and Mr. Phillips' testimony on this topic and my explanation of the background and purpose of the TFO provisions, I would suggest using the following language for Section 6(u): "Any commercial entity receiving Utility's charges to Customer and assuming responsibility for remitting payment of Utility's charges from or on behalf of Customer must sign an agreement provided by Utility governing the remittance to Utility of amounts owed by customer to Utility, including IFC payments." Similar changes should be made to Section 7.B of SC 110. This language would be consistent with the intended coverage of the TFO provisions, as I have explained.

IV. Revenue Requirement

34. Q. Please describe IP Exhibit 3.24.

A. IP Exhibit 3.24 shows the development of the Company's revised electric distribution revenue requirement, reflecting changes to various rate base and operating expense components as described in the surrebuttal testimonies and exhibits sponsored by IP witnesses Carter, Barud, and me. These revisions include the impact of the Company's full or partial acceptance of positions of Staff and intervenor witnesses. Line 29, Revenue Requirement for Individual Columns, changes for each column due to the impact of the revised cost of capital as well as changes to rate base, operating expenses and the gross up of deferred ITC tax amortization. The following list describes each column of IP Exhibit 3.24, identifies those columns that have been revised or added, as compared to IP Exhibit 3.15, and references the exhibit(s) which is the source of each of these columns:

* Column (2): This column shows the unadjusted functionalized balances for each component of rate base and operating expenses as of December 31, 2000. See IP Exhibits 1.15 (Carter).
* Column (3): This column shows the adjustments for Energy Delivery Rate Base Additions and the related Accumulated Provision for Depreciation and Amortization, and Depreciation and Amortization Expense. See IP Exhibits 1.65, 1.67 and 1.75 (Carter) and 2.18-2.20 (Barud).
* Column (4): This column shows the adjustment for Corporate Capital Additions and the related Accumulated Provision for Depreciation and Amortization and Depreciation and Amortization Expense. See IP Exhibits 1.64, 1.65, 1.67 and 1.75 (Carter).
* Column (5): This column shows the adjustment for the Load Research Program. See IP Exhibits 6.1 and 6.5 (Jones) and 1.65, 1.67 and 1.75 (Carter).

* Column (6): This column shows the adjustment for FAS 109 Gross-up. See IP Exhibit 1.6 and 1.65 (Carter).
* Column (7): This column shows the adjustment for CWIP transferred to Utility Plant in Service. See Corrected Revised IP Exhibit 1.7 and IP Exhibits 1.65, 1.67 and 1.75 (Carter).
* Column (8): This column shows the adjustment for Facilities No Longer in Use. See IP Exhibits 1.8, 1.29, 1.65, 1.67 and 1.75 (Carter).
* Column (9): This column shows the adjustment for Cash Working Capital. See IP Exhibit 1.66 (Carter).
* Column (10): This column shows the adjustment for Rate Case Expense. See IP Exhibit 1.16 (Carter).
* Column (11): This column shows the adjustment for Postal Rate Increase. See IP Exhibit 1.17 (Carter).
* Column (12): This column shows the adjustment for Insurance Expense. See IP Exhibit 1.18 (Carter).
* Column (13): This column shows the adjustment for costs of the Standards of Conduct/Functional Separation Rulemaking. See IP Exhibit 1.19 (Carter).
* Column (14): This column shows the adjustment for costs of the Affiliate Transactions rulemaking. See IP Exhibit 1.20 (Carter).

* Column (15): This column shows the adjustment for Y2K Expense. See IP Exhibit 1.45 (Carter).
* Column (16): This column shows the adjustment associated with the cost of Company use of electricity. See IP Exhibit 1.24 (Carter).
* Column (17): This column shows the adjustment for pass-through taxes. See IP Exhibit 1.25 (Carter).
* Column (18): This column shows the adjustment for increased payroll costs. See IP Exhibit 1.76 (Carter).
* Column (19): This column shows the adjustment for Federal Insurance Contributions Act taxes. See IP Exhibit 1.27 (Carter).
* Column (20): This column shows the adjustment for severance costs and transition employees. See Corrected Revised IP Exhibit 1.28 (Carter).
* Column (21): This column shows the adjustment for Dynegy senior executive compensation. See IP Exhibit 1.77 (Carter).
* Column (22): This column shows the adjustment for implementation of the Operations Compliance Group. See IP Exhibit 2.1 (Barud).
* Column (23): This column shows the adjustment to normalize storm damage expense. See IP Exhibit 2.11 (Barud).

* Column (24): This column shows the adjustment for Accumulated Depreciation of Plant in Service as of December 31, 2000, through September 30, 2001. See IP Exhibit 1.74 (Carter).
* Column (25): This column shows the adjustment for Accumulated Deferred Taxes on Plant in Service as of December 31, 2000, through September 30, 2001. See IP Exhibit 1.74 (Carter).
* Column (26): This column shows the adjustment to Unamortized Pre-1971 Investment Tax Credit, as proposed by CUB/AG witness Effron. The amount in this column has been revised to correct an error in my rebuttal exhibit, IP Exhibit 3.15.
* Column (27): This column shows the adjustment to remove the test year expense for the "Duke Engineering" litigation, as proposed by CUB/AG witness Effron.
* Column (28): This column shows the adjustments to remove a portion of EEI Dues that is used for lobbying purposes, as proposed by Staff witness Pearce.
* Column (29): This column shows the adjustment to amortize certain test year Injuries and Damages costs. See IP Exhibit 1.60. (Carter).
* Column (30): This column shows the adjustment for use of the correct allocation method under Services and Facilities Agreement for charges billed by Dynegy, as proposed by Staff witness Hathhorn.
* Column (31): This column shows the adjustment to eliminate certain reimbursements to Clinton Power Station employees, as proposed by Staff witness Hathhorn.

* Column (32): This column shows the adjustment for additional metering and billing expenses relating to the additional customers at year end 2000 included in the billing determinants as proposed by CUB/AG witness Effron. See IP Exhibit 8.13 (Althoff).
* Column (33): This column shows the adjustment to remove the expense for IP's pro rata share of the annual contribution to the Energy Efficiency Fund, as proposed by Staff witness Pearce.
* Column (34): This column shows the adjustment to remove Illinois Energy Association dues as proposed by Staff witness Pearce. See IP Exhibit 1.73 (Carter).
* Column (35): This column shows the Total Pro Forma Adjustments. The Total Pro Forma Adjustments are revised from the total shown on IP Exhibit 3.15 due to the changes and/or additions to the adjustments in Columns (3), (4), (9), (18), (21), (24), (25), (26), (27) and (34).
* Column (36) This column shows the adjusted Total Rate Base and Total Operating Expenses. Total Rate Base is now $909,163,000 (versus $931,315,000 on IP Exhibit 3.15). Total Operating Expenses are now $190,146,000 (versus $190,357,000 on IP Exhibit 3.16).

35. Q. Please describe IP Exhibit 3.25

A. IP Exhibit 3.25 presents the calculation of the electric distribution revenue requirement based on the Company's surrebuttal position. Comparing page 1 of IP Exhibit 3.25 to page 1 of IP Exhibit 3.16: (1) Line (1), Net Rate Base, is now lower by $22,152,000 due to the aggregate impact of the revisions to rate base presented by IP witnesses Carter and Barud; (2) Line (2), Before-Tax Weighted Cost of Capital, is lower (8.92% vs. 9.17%) as a result of the changes I described earlier in this testimony; (3) Line (3), Return Requirement, is now lower by $4,305,000 due to the changes to Lines (1) and (2); (4) Line (4), Income Tax Savings Due to Interest Synchronization Deduction, is now lower by $1,597,000 due to the changes to Original Cost Rate Base and to the Weighted Cost of Debt, as shown on page 2 of IP Exhibit 3.25; (5) Line (4a), shows the Amortization of Investment Tax Credit, as proposed by CUB/AG witness Effron; (6) Line (5), After-tax Rate Base Return Requirement, is now lower by $2,708,000 as a result of the changes to Lines (1) through (4); (7) Line (6), Times Gross-up Conversion Factor, uses the conversion factor of 1.66431 reflecting inclusion of an uncollectible factor of .0041 in the gross-up conversion factor as proposed by Staff witness Hathhorn; (8) Line (7), Requested Return Grossed Up for Income Taxes, is now lower by $4,507,000, as a result of changes to Lines (1) though (4a); and (9) Line (8), Operating Expenses before Income Taxes, is now lower by $211,000 due to the changes to various operating statement components presented by IP witness Carter in her surrebuttal testimony. The resulting electric distribution revenue requirement, shown on Line (10) on page 1 of IP Exhibit 3.25, is now $299,430,000, as compared to an electric distribution revenue requirement of $304,148,000 shown on page 1 of IP Exhibit 3.16, i.e., a decrease of $4,718,000.

36. Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Illinois Power Company
Embedded Cost of Preferred Stock
Net Proceeds Method
As of August 31, 2001

Line No.	Dividend rate, type, par value		Date Issued	Maturity Date	Number of Shares Outstanding	Par Value Outstanding	Premium or (Discount)	Unamortized Issue Expense	Net proceeds (5)+(6)-(7)	Annual Amortization of Discount or Premium	Annual Amortization of Issue Expense	Annual Dividends	Annual Dividend Expense (9)+(10)+(11)
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**Preferred Stock (non-tax advantaged)**												
2													
3	Serial preferred stock, cumulative, $50 par value												
4													
5		4.080%	04/24/1950	N/A	225,510	$11,275,500	$224,334	$203,254	$11,296,580	$0	$0	$460,040	$460,040
6		4.260%	11/01/1950	N/A	104,280	5,214,000	10,366	24,676	5,199,690	-	-	222,116	222,116
7		4.700%	03/10/1952	N/A	145,170	7,258,500	-	32,156	7,226,344	-	-	341,150	341,150
8		4.420%	02/11/1953	N/A	102,190	5,109,500	-	27,494	5,082,006	-	-	225,840	225,840
9		4.200%	09/23/1954	N/A	143,760	7,188,000	-	34,145	7,153,855	-	-	301,896	301,896
10		7.750%	06/21/1994	N/A	191,765	9,588,250	(81,505)	35,076	9,471,669	-	-	743,089	743,089
11													
12	**Total August 31, 2001**					$45,633,750	$153,194	$356,799	$45,430,145	$0	$0	$2,294,132	$2,294,132
13													
14												**Embedded Cost of Preferred Stock (non-tax advantaged)**	**5.05%**
15													
16	**Preferred Securities (tax advantaged)**												
17													
18	Mandatorily Redeemable Preferred Securities												
19													
20	MIPS	9.45%	10/06/1994	05/01/2000		$0	$0	$2,784,445	($2,784,445)	$0	$65,894	$0	$65,894
21													
22	TOPrS	8.00%	01/17/1996	01/01/2045		100,000,000	-	2,917,934	97,082,066	-	67,321	8,000,000	8,067,321
23													
24	**Total August 31, 2001**					$100,000,000	$0	$5,702,378	$94,297,622		$133,215	$8,000,000	$8,133,215
25													
26												**Embedded Cost of Preferred Securities (tax advantaged)**	**8.63%**

Note : No pro forma adjustments for Preferred Stock or Preferred Securities

IP Exhibit 3.19

Illinois Power Company
Embedded Cost of Long-Term Debt
Net Proceeds Method
As of August 31, 2001

	Debt Type (1)	Debt Issue (2)	Date Issued (3)	Maturity Date (4)	Principal Amount (5)	Face Amount Outstanding (6)	Unamortized Debt Discount (Premium) (7)	Unamortized Debt Expense (8)	Carrying Value (6)-(7)-(8) (9)	Annualized Coupon Expense (2) x (6) (10)	Annualized Amortization of Debt Discount (Premium) (11)	Annualized Amortization of Debt expense (12)	Annualized Interest Expense (10)+(11)+(12) (13)
1	Loss on Reacquired Debt	Series 14.5% & 12%	09/01/1996	09/01/2016	$150,000,000	$0	$0	$9,791,960	($9,791,960)	$0	$0	$652,800	$652,800
2	Loss on Reacquired Debt	Series 7.600%	12/01/1993	10/01/2001	35,000,000			8,023	(8,023)			8,023	8,023
3	Loss on Reacquired Debt	Series 7.625%	09/01/1993	04/01/2003	60,000,000			265,099	(265,099)			167,424	167,424
4	Loss on Reacquired Debt	Series 10.500%	05/01/1991	09/01/2004	50,000,000			489,867	(489,867)			163,284	163,284
5	Loss on Reacquired Debt	Series 8.625%	04/01/1993	03/01/2005	100,000,000			1,256,703	(1,256,703)			359,058	359,058
6	Loss on Reacquired Debt	PCB Series C 10.750%	07/01/1991	11/01/2028	150,000,000			4,925,492	(4,925,492)			181,308	181,308
7	Loss on Reacquired Debt	PCB Series D 11.625%	05/01/1994	02/01/2024	75,000,000			1,520,221	(1,520,221)			67,812	67,812
8	Loss on Reacquired Debt	PCB Series E 10.750%	07/01/1991	12/01/2024	150,000,000			2,475,607	(2,475,607)			106,476	106,476
9	Loss on Reacquired Debt	Series 9.875%	11/01/1990	07/01/2016	75,000,000			274,209	(274,209)			18,486	18,486
10	Loss on Reacquired Debt	Series 9.375%	03/01/1993	02/01/2023	125,000,000			7,158,744	(7,158,744)			334,260	334,260
11	Loss on Reacquired Debt	PCB Series F,G,H 7.625%	06/01/1997	04/01/2032	150,000,000			5,500,351	(5,500,351)			179,844	179,844
12	Loss on Reacquired Debt	PCB Series I 8.300%	07/01/1987	04/01/2017	33,755,000			3,657,815	(3,657,815)			234,726	234,726
13	Loss on Reacquired Debt	Series 8.875%	03/01/1993	02/01/2023	100,000,000			3,608,035	(3,608,035)			168,468	168,468
14	Loss on Reacquired Debt	Series 12.000%	01/01/1988	11/01/2012	75,000,000			322,578	(322,578)			28,884	28,884
15	Loss on Reacquired Debt	Series 7.500%	08/01/1993	07/15/2025	200,000,000			2,269,447	(2,269,447)			227,640	227,640
16	Loss on Reacquired Debt	PCB Series 5.400%	03/01/1998	03/01/2028	52,455,000			1,153,545	(1,153,545)			43,530	43,530
17	Loss on Reacquired Debt	PCB Series 7.375%	07/01/1999	12/01/2008	84,710,000			7,623,170	(7,623,170)			1,039,524	1,039,524
18	Loss on Reacquired Debt	Series 7.950%	12/01/1998	12/01/2008	72,000,000			3,145,065	(3,145,065)			428,868	428,868
19	Loss on Reacquired Debt	Series 8.750%	01/01/1999	12/01/2008	125,000,000			4,606,260	(4,606,260)			628,128	628,128
20													
21	New Mortgage Bond	Series 6.500%	08/01/1993	08/01/2003	100,000,000	100,000,000	247,338	26,733	99,725,929	6,500,000	128,778	13,918	6,642,696
22													
23	New Mortgage Bond	Series 6.750%	03/15/1993	03/15/2005	70,000,000	70,000,000	189,441	36,357	69,774,202	4,725,000	53,499	10,268	4,788,767
24													
25	Auction Rate Debt	PCB Series X Adjustable	05/01/2001	03/01/2017	75,000,000	75,000,000		1,894,143	73,105,857	2,512,500		122,208	2,634,708
26	Auction and Remarketing Fees	PCB Series X Adjustable	05/01/2001	03/01/2017	75,000,000					415,092			415,092
27		Loss on Reacquired Debt						536,347	(536,347)			34,608	34,608
28	New Mortgage Bond	PCB Series U 5.700%	02/01/1994	02/01/2024	35,615,000	35,615,000	4,986,747	1,367,740	29,260,513	2,030,055	222,239	60,955	2,313,249
29													
30	New Mortgage Bond	PCB Series V 7.400%	12/01/1994	12/01/2024	84,150,000	84,150,000	653,836	3,012,553	80,483,611	6,227,100	28,096	129,452	6,384,648
31													
32	New Mortgage Bond	Series 7.500%	07/22/1993	07/15/2025	200,000,000	65,630,000	723,034	66,745	64,840,221	4,922,250	30,265	2,794	4,955,309
33													
34	Auction Rate Debt	PCB Series W Adjustable	05/01/2001	11/01/2028	111,770,000	111,770,000		3,548,892	108,221,108	3,744,295		130,632	3,874,927
35	Auction and Remarketing Fees	PCB Series W Adjustable	05/01/2001	11/01/2028	111,770,000					564,256			564,256
36		Loss on Reacquired Debt						1,391,759	(1,391,759)			51,228	51,228
37	New Mortgage Bond	PCB Series P,Q,R Adjustable	04/10/1997	04/01/2032	150,000,000	150,000,000		2,654,761	147,345,239	5,025,000		86,733	5,111,733
38	Remarketing and LOC Fees	PCB Series P,Q,R Adjustable	04/10/1997	04/01/2032	150,000,000					301,726			301,726
39													
40	New Mortgage Bond	PCB Series S 5.400%	03/06/1998	03/01/2028	18,700,000	18,700,000		516,993	18,183,007	1,009,800		19,494	1,029,294
41													
42	New Mortgage Bond	PCB Series T 5.400%	03/06/1998	03/01/2028	33,755,000	33,755,000		522,187	33,232,813	1,822,770		19,690	1,842,460
43													
44	New Mortgage Bond	Series 6.250%	07/15/1998	07/15/2002	100,000,000	95,675,000	14,165	183,379	95,477,456	5,979,688	16,330	211,369	6,207,387
45													
46	New Mortgage Bond	Series 6.000%	09/16/1998	09/15/2003	100,000,000	90,000,000	73,267	312,718	89,614,016	5,400,000	35,900	153,227	5,589,127
47													
48	New Mortgage Bond	Series 7.500%	06/29/1999	06/15/2009	250,000,000	250,000,000	287,230	1,836,704	247,876,067	18,750,000	36,839	235,574	19,022,413
49													
50	**Total Long-Term Debt 2000 Ending Balances, Adjusted**					$1,180,295,000	$7,175,057	$77,960,201	$1,095,159,742	$69,929,532	$551,946	$6,320,693	$76,802,171
51													
												Embedded Cost of Long Term Debt	7.01%

NOTE: Long-term debt ties to 2000 FERC Form 1 excluding the Fair Market Value Adjustment of $10.5 million . Loss on reacquired debt is presented here as if the Company had not discontinued accounting for generation assets under FAS 71.

Illinois Power Company
Transitional Funding Instruments
(Dollars Unless Otherwise Indicated)

Month No.	Date	Collection Amount	Discount Factor	Present Value	Month No.	Date	Collection Amount	Discount Factor	Present Value
1	Sep-01	$ 10,329,650	0.995418	(10,282,322)	45	May-05	$ 8,743,208	0.813300	(7,110,852)
2	Oct-01	10,234,070	0.990857	(10,140,504)	46	Jun-05	8,743,208	0.809574	(7,078,271)
3	Nov-01	10,234,070	0.986317	(10,094,042)	47	Jul-05	8,644,822	0.805864	(6,966,553)
4	Dec-01	10,234,070	0.981798	(10,047,793)	48	Aug-05	8,644,822	0.802172	(6,934,634)
5	Jan-02	9,997,498	0.977300	(9,770,554)	49	Sep-05	8,644,822	0.798497	(6,902,861)
6	Feb-02	9,997,498	0.972822	(9,725,788)	50	Oct-05	8,545,102	0.794838	(6,791,972)
7	Mar-02	9,997,498	0.968365	(9,681,226)	51	Nov-05	8,545,102	0.791196	(6,760,853)
8	Apr-02	9,901,918	0.963928	(9,544,736)	52	Dec-05	8,545,102	0.787571	(6,729,876)
9	May-02	9,901,918	0.959511	(9,501,004)	53	Jan-06	8,445,382	0.783963	(6,620,864)
10	Jun-02	9,901,918	0.955115	(9,457,472)	54	Feb-06	8,445,382	0.780371	(6,590,528)
11	Jul-02	9,806,028	0.950739	(9,322,973)	55	Mar-06	8,445,382	0.776795	(6,560,332)
12	Aug-02	9,806,028	0.946383	(9,280,257)	56	Apr-06	8,345,662	0.773236	(6,453,166)
13	Sep-02	9,806,028	0.942047	(9,237,737)	57	May-06	8,345,662	0.769693	(6,423,599)
14	Oct-02	9,709,908	0.937730	(9,105,277)	58	Jun-06	8,345,662	0.766167	(6,394,168)
15	Nov-02	9,709,908	0.933434	(9,063,558)	59	Jul-06	8,245,942	0.762656	(6,288,819)
16	Dec-02	9,709,908	0.929157	(9,022,031)	60	Aug-06	8,245,942	0.759162	(6,260,005)
17	Jan-03	9,613,788	0.924900	(8,891,792)	61	Sep-06	8,245,942	0.755684	(6,231,322)
18	Feb-03	9,613,788	0.920662	(8,851,052)	62	Oct-06	8,146,222	0.752221	(6,127,760)
19	Mar-03	9,613,788	0.916444	(8,810,498)	63	Nov-06	8,146,222	0.748775	(6,099,684)
20	Apr-03	9,517,668	0.912245	(8,682,445)	64	Dec-06	8,146,222	0.745344	(6,071,736)
21	May-03	9,517,668	0.908065	(8,642,663)	65	Jan-07	8,046,502	0.741929	(5,969,932)
22	Jun-03	9,517,668	0.903905	(8,603,064)	66	Feb-07	8,046,502	0.738529	(5,942,579)
23	Jul-03	9,421,088	0.899763	(8,476,748)	67	Mar-07	8,046,502	0.735146	(5,915,351)
24	Aug-03	9,421,088	0.895641	(8,437,909)	68	Apr-07	7,946,782	0.731777	(5,815,275)
25	Sep-03	9,421,088	0.891537	(8,399,248)	69	May-07	7,946,782	0.728425	(5,788,630)
26	Oct-03	9,324,248	0.887452	(8,274,823)	70	Jun-07	7,946,782	0.725087	(5,762,108)
27	Nov-03	9,324,248	0.883386	(8,236,910)	71	Jul-07	7,846,200	0.721765	(5,663,111)
28	Dec-03	9,324,248	0.879338	(8,199,170)	72	Aug-07	7,846,200	0.718458	(5,637,164)
29	Jan-04	9,227,408	0.875309	(8,076,838)	73	Sep-07	7,846,200	0.715166	(5,611,335)
30	Feb-04	9,227,408	0.871299	(8,039,831)	74	Oct-07	7,744,500	0.711889	(5,513,226)
31	Mar-04	9,227,408	0.867307	(8,002,994)	75	Nov-07	7,744,500	0.708627	(5,487,965)
32	Apr-04	9,130,568	0.863333	(7,882,721)	76	Dec-07	7,744,500	0.705381	(5,462,821)
33	May-04	9,130,568	0.859377	(7,846,604)	77	Jan-08	7,642,800	0.702149	(5,366,383)
34	Jun-04	9,130,568	0.855440	(7,810,652)	78	Feb-08	7,642,800	0.698932	(5,341,795)
35	Jul-04	9,033,728	0.851520	(7,692,404)	79	Mar-08	7,642,800	0.695729	(5,317,320)
36	Aug-04	9,033,728	0.847619	(7,657,159)	80	Apr-08	7,541,100	0.692542	(5,222,525)
37	Sep-04	9,033,728	0.843735	(7,622,075)	81	May-08	7,541,100	0.689368	(5,198,597)
38	Oct-04	8,936,888	0.839869	(7,505,819)	82	Jun-08	7,541,100	0.686210	(5,174,778)
39	Nov-04	8,936,888	0.836021	(7,471,429)	83	Jul-08	7,439,400	0.683066	(5,081,600)
40	Dec-04	8,936,888	0.832191	(7,437,197)	84	Aug-08	7,439,400	0.679936	(5,058,317)
41	Jan-05	8,840,048	0.828378	(7,322,901)	85	Sep-08	7,439,400	0.676821	(5,035,141)
42	Feb-05	8,840,048	0.824582	(7,289,348)	86	Oct-08	7,337,700	0.673720	(4,943,554)
43	Mar-05	8,840,048	0.820804	(7,255,950)	87	Nov-08	7,337,700	0.670633	(4,920,903)
44	Apr-05	8,743,208	0.817044	(7,143,582)	88	Dec-08	(1,302,300)	0.667560	869,364
			Sub-Total	$ (377,841,101)				Sub-Total	$ (255,758,899)

Amount (over)/undercollected Jan-Jun 2001=	$845,952
With Discount Rate = 5.67% Total PV=	(633,600,000)
Net Proceeds=	633,600,000
NPV=	(0)

		Ending Balances as of August 2001	Interest/ Amortization
	TFI Balance	$ 633,600,000	$ 35,925,120
Less:	Discount	60,527.66	8,348.64
	Debt Expense	4,730,173.56	652,437.96
	Unamortized Loss	38,021,162.56	5,244,298.20
		$ 590,788,136.22	$ 41,830,204.80
	Cost Rate		7.08%

Illinois Power Company
Embedded Cost of Short-Term Debt
(Dollars Unless Otherwise Indicated)

Line No.	Month (1)	Balance of Short-Term Debt (1) (2)	Balance of CWIP Accruing AFUDC (3)	Net Amount Outstanding (A) (2-3) (4)	Two-Month Average (5)	Annualized Interest (6)
Notes Payable						
1	February 2001	$140,585,784	$16,455,314	$124,130,470		
2	March	274,513,346	22,721,396	251,791,951	$187,961,210	
3	April	206,653,438	29,254,492	177,398,947	214,595,449	
4	May	202,185,286	32,275,943	169,909,343	173,654,145	
5	June	197,227,497	38,373,096	158,854,401	164,381,872	
6	July	191,378,624	42,189,098	149,189,526	154,021,964	
7	August	193,367,246	44,726,225	148,641,022	148,915,274	
8	September	232,837,000	16,560,020	216,276,980	182,459,001	
9	October	136,241,000	17,650,525	118,590,475	167,433,728	
10	November	143,762,000	18,789,540	124,972,460	121,781,468	
11	December	205,867,000	16,292,892	189,574,108	157,273,284	
12	January 2002	209,145,000	21,770,525	187,374,475	188,474,292	
13	February	203,728,000	23,166,885	180,561,115	183,967,795	
14	Average				170,409,957	
15	Commercial Paper Rate at August 2001				3.8500%	
16	Annualized Interest on Short-term Debt					$6,560,783 (B)

Revolving Credit Agreement

Line No.		Outstanding	Annual Fee
17	Revolving Credit Agreement in Support of Commercial Paper	$300,000,000	
18	Revolving Credit Agreement Facility Fee	0.125%	
19	Annual Fee on Revolving Credit Agreement		$375,000 (C)
20	Percentage of Commercial Paper to Revolving Credit Agreement		56.8%
21	Revolving Credit Agreement Cost in Support of Commercial Paper		$213,012 (D)

Effective Commercial Paper Rate

Line No.		
22	**Effective Commercial Paper Annualized Interest**	$6,773,796 (E)
23	**Effective Commercial Paper Rate**	**3.98%**

(A) Monthly averages excluding negative amounts.
(B) Column 5 line 14 times Column 5 line 15.
(C) Column 5 line 17 times Column 5 line 18.
(D) Column 6 line 19 times Column 6 line 20.
(E) Column 6 line 16 plus Column 6 line 21.

Illinois Power Company
Common Stock Equity
for 2001
(Dollars)

Line No. (1)	Month (2)	Paid-in Capital (3)	Retained Earnings (4)	Common Stock Expense (5)	Treasury Stock (6)	Total Common Stock Equity (3)+(4)+(5)+(6) (7)
1	August 2001	$1,274,199,742	$205,806,289	$(7212200.35)	$(286367910)	$1,186,425,920

ILLINOIS POWER COMPANY
SUMMARY OF RATE BASE AND OPERATING EXPENSES AND PRO FORMA ADJUSTMENTS
($000)

Line No.	Description	December 31, 2000	Proforma #1 Energy Delivery Rate Base Additions	Proforma #2 Corporate Capital Additions Adjustment	Proforma #3 Load Research Adjustment	Proforma #4 FAS 109 Gross-up Adjustment	Proforma #5 Plant Transfer from CWIP to UPIS Adjustment	Proforma #6 Facilities No Longer in Use Adjustment	Proforma #7 Cash Working Capital Adjustment	Proforma #8 Rate Case Expense Adjustment	Proforma #9 Postal Rate Increase Adjustment	Proforma #10 Insurance Expense Adjustment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	RATE BASE											
	Plant in Service											
1	Distribution Plant in Service	$1,392,655.0	$80,196.0	-	$1,606.0	($2,101.0)	-	-	-	-	-	-
2	General Plant in Service	193,902.0	1,976.0	$7,400.0	-	(115.0)	$5,913.0	($7,346.0)	-	-	-	-
3	Intangible Plant in Service	63,479.0	1,303.0	3,387.0	-	-	2,545.0	-	-	-	-	-
4	Accumulated Deprec - Distribution	(573,562.0)	19,159.0	-	(19.0)	717.0	-	-	-	-	-	-
5	Accumulated Deprec - General	(47,759.0)	67.0	7,284.0	-	75.0	(74.0)	6,934.0	-	-	-	-
6	Accumulated Deprec - Intangible	(49,696.0)	(130.0)	(339.0)	-	-	(255.0)	-	-	-	-	-
7	**Net Plant in Service**	979,019.0	102,571.0	17,732.0	1,587.0	(1,424.0)	8,129.0	(412.0)	-	-	-	-
	Adjustments											
	Add:											
8	Land Held for Future Use	-	-	-	-	-	-	-	-	-	-	-
9	CWIP - Not Including AFUDC	5,592.0	-	-	-	-	-	-	-	-	-	-
10	Depr Res - Contrib Electric Distribution	2,870.0	-	-	-	-	-	-	-	-	-	-
11	Working Capital	6,873.0	-	-	-	-	-	-	3,087.0	-	-	-
	Less:											
12	Reserve for Deferred Income Taxes	(173,375.0)	(2,388.0)	(1,670.0)	(33.0)	-	(289.0)	255.0	-	-	-	-
13	Customer Deposit Balance	(2,044.0)	-	-	-	-	-	-	-	-	-	-
14	Customer Advances for Construction	(1,032.0)	-	-	-	-	-	-	-	-	-	-
15	Pre-1971 ITC	(564.0)	-	-	-	-	-	-	-	-	-	-
16	**Total Adjustments**	(161,680.0)	(2,388.0)	(1,670.0)	(33.0)	-	(289.0)	255.0	3,087.0	-	-	-
17	**Total Rate Base**	$817,339.0	$100,183.0	$16,062.0	$1,554.0	($1,424.0)	$7,840.0	($157.0)	$3,087.0	$0.0	$0.0	$0.0
	Operating Expenses											
18	Operation & Maintenance	$51,243.0	-	-	$144.0	-	-	-	-	-	-	-
19	Customer Accounts Expense	12,087.0	-	-	-	-	-	-	-	-	$68.0	-
20	Customer Service and Informational Expense	4,950.0	-	-	-	-	-	-	-	-	-	-
21	Sales Expense	-	-	-	-	-	-	-	-	-	-	-
22	Administrative and General Expenses	63,521.0	-	-	-	-	$86.0	($193.0)	-	$494.0	-	$2,619.0
23	Depreciation Expense - Distribution Plant	31,890.0	$1,861.0	-	38.0	-	-	-	-	-	-	-
24	Depreciation Expense - General Plant	4,983.0	37.0	$173.0	-	-	148.0	(152.0)	-	-	-	-
25	Amortization Expense - Intangible Plant	5,659.0	261.0	677.0	-	-	509.0	-	-	-	-	-
26	Taxes Other Than Income	45,656.0	-	-	-	-	96.0	(73.0)	-	-	-	-
27	Investment Tax Credit Adjustment - Net	(573.0)	-	-	-	-	-	-	-	-	-	-
28	**Total Operating Expenses**	$219,416.0	$2,159.0	$850.0	$182.0	$0.0	$839.0	($418.0)	$0.0	$494.0	$68.0	$2,619.0
29	Revenue Requirement for Individual Columns	$318,579.0	$14,243.0	$2,789.0	$370.0	($172.0)	$1,785.0	($437.0)	$372.0	$494.0	$68.0	$2,619.0

ILLINOIS POWER COMPANY
SUMMARY OF RATE BASE AND OPERATING EXPENSES AND PRO FORMA ADJUSTMENTS
($000)

Line No.	Description	Proforma #11 Conduct/Functional Separation Rulemaking	Proforma #12 Affiliate Transaction Rulemaking	Proforma #13 Y2K Expense	Proforma #14 Company Use Adjustment	Proforma #15 Pass-Thru Revenue Tax Elimination	Proforma #16 Payroll Adjustment	Proforma #17 FICA Tax Adjustment	Proforma #18 Severance / Transition Adjustment	Proforma #19 Dynegy Executive Bonuses Adjustment	Proforma #20 Operations Compliance Expense	Proforma #21 Storm Damage Normalization Expense	Proforma #22 Accum Deprec on Embedded Plant 12/00 -6/30/02
	(1)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
	RATE BASE												
	Plant in Service												
1	Distribution Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-
2	General Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-
3	Intangible Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deprec - Distribution	-	-	-	-	-	-	-	-	-	-	-	(23,918.0)
5	Accumulated Deprec - General	-	-	-	-	-	-	-	-	-	-	-	(3,737.0)
6	Accumulated Deprec - Intangible	-	-	-	-	-	-	-	-	-	-	-	(4,244.0)
7	**Net Plant in Service**	-	-	-	-	-	-	-	-	-	-	-	(31,899.0)
	Adjustments												
	Add:												
8	Land Held for Future Use	-	-	-	-	-	-	-	-	-	-	-	-
9	CWIP - Not Including AFUDC	-	-	-	-	-	-	-	-	-	-	-	-
10	Depr Res - Contrib Electric Distribution	-	-	-	-	-	-	-	-	-	-	-	-
11	Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
	Less:												
12	Reserve for Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-
13	Customer Deposit Balance	-	-	-	-	-	-	-	-	-	-	-	-
14	Customer Advances for Construction	-	-	-	-	-	-	-	-	-	-	-	-
15	Pre-1971 ITC	-	-	-	-	-	-	-	-	-	-	-	-
16	**Total Adjustments**	-	-	-	-	-	-	-	-	-	-	-	-
17	**Total Rate Base**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($31,899.0)
	Operating Expenses												
18	Operation & Maintenance	-	-	($52.0)	$1,127.0	-	$762.0	-	($867.0)	-	$77.0	$581.0	-
19	Customer Accounts Expense	-	-	1.0	-	-	185.0	-	(211.0)	-	-	-	-
20	Customer Service and Informational Expense	-	-	-	-	-	115.0	-	(131.0)	-	-	-	-
21	Sales Expense	-	-	-	-	-	-	-	-	-	-	-	-
22	Administrative and General Expenses	$14.0	$51.0	86.0	-	-	348.0	-	(12,521.0)	($7,445.0)	-	-	-
23	Depreciation Expense - Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-
24	Depreciation Expense - General Plant	-	-	-	-	-	-	-	-	-	-	-	-
25	Amortization Expense - Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-
26	Taxes Other Than Income	-	-	-	-	($12,067.0)	-	$52.0	(377.0)	-	-	-	-
27	Investment Tax Credit Adjustment - Net	-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Operating Expenses**	$14.0	$51.0	$35.0	$1,127.0	($12,067.0)	$1,410.0	$52.0	($14,107.0)	($7,445.0)	$77.0	$581.0	$0.0
29	Revenue Requirement for Individual Columns	$14.0	$51.0	$35.0	$1,127.0	($12,067.0)	$1,410.0	$52.0	($14,107.0)	($7,445.0)	$77.0	$581.0	($3,847.0)

ILLINOIS POWER COMPANY
SUMMARY OF RATE BASE AND OPERATING EXPENSES AND PRO FORMA ADJUSTMENTS
($000)

Line No.	Description	Proforma #23 Accum Def Inc Taxes on Embedded Plant 12/00 -6/30/02	Proforma #24 Unamortized Pre-1971 ITC	Proforma #25 Duke Litigation Expense	Proforma #26 EEi Dues Adjustment	Proforma #27 Insurance Accrual Amortization	Proforma #28 Services & Facilities Adjustment	Proforma #29 Eliminate Clinton NPS Expenses	Proforma #30 Meter/ Billing Expense Adjustment	Proforma #31 Energy Efficiency Adjustment	Proforma #32 Illinois Energy Association Adjustment	Revised Total Pro Forma Adjustments (Col. 3 thru Col. 34)	Revised Adjusted Deceber 31, 2000 (Col. 2 plus Col.35)
	(1)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)
	RATE BASE												
	Plant in Service												
1	Distribution Plant in Service	-	-	-	-	-	-	-	-	-	-	$79,701.0	$1,472,356.0
2	General Plant in Service	-	-	-	-	-	-	-	-	-	-	7,828.0	201,730.0
3	Intangible Plant in Service	-	-	-	-	-	-	-	-	-	-	7,235.0	70,714.0
4	Accumulated Deprec - Distribution	-	-	-	-	-	-	-	-	-	-	(4,061.0)	(577,623.0)
5	Accumulated Deprec - General	-	-	-	-	-	-	-	-	-	-	10,549.0	(37,210.0)
6	Accumulated Deprec - Intangible	-	-	-	-	-	-	-	-	-	-	(4,968.0)	(54,664.0)
7	**Net Plant in Service**	-	-	-	-	-	-	-	-	-	-	96,284.0	1,075,303.0
	Adjustments												
	Add:												
8	Land Held for Future Use	-	-	-	-	-	-	-	-	-	-	-	-
9	CWIP - Not Including AFUDC	-	-	-	-	-	-	-	-	-	-	-	5,592.0
10	Depr Res - Contrib Electric Distribution	-	-	-	-	-	-	-	-	-	-	-	2,870.0
11	Working Capital	-	-	-	-	-	-	-	-	-	-	3,087.0	9,960.0
												-	-
	Less:											-	-
12	Reserve for Deferred Income Taxes	(3,448.0)	-	-	-	-	-	-	-	-	-	(7,573.0)	(180,948.0)
13	Customer Deposit Balance	-	-	-	-	-	-	-	-	-	-	-	(2,044.0)
14	Customer Advances for Construction	-	-	-	-	-	-	-	-	-	-	-	(1,032.0)
15	Pre-1971 ITC	-	26.0	-	-	-	-	-	-	-	-	26.0	(538.0)
16	**Total Adjustments**	(3,448.0)	26.0	-	-	-	-	-	-	-	-	(4,460.0)	(166,140.0)
17	**Total Rate Base**	($3,448.0)	$26.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$91,824.0	$909,163.0
	Operating Expenses												
18	Operation & Maintenance	-	-	-	-	-	-	-	-	-	-	$ 1,772.0	$53,015.0
19	Customer Accounts Expense	-	-	-	-	-	-	-	33.0	-	-	76.0	12,163.0
20	Customer Service and Informational Expense	-	-	-	-	-	-	-	-	(446.0)	-	(462.0)	4,488.0
21	Sales Expense	-	-	-	-	-	-	-	-	-	-	-	-
22	Administrative and General Expenses	-	-	(1,030.0)	(14.0)	(3,225.0)	(1,035.0)	(2.0)	-	-	(72.0)	(21,839.0)	41,682.0
23	Depreciation Expense - Distribution Plant	-	-	-	-	-	-	-	-	-	-	1,899.0	33,789.0
24	Depreciation Expense - General Plant	-	-	-	-	-	-	-	-	-	-	206.0	5,189.0
25	Amortization Expense - Intangible Plant	-	-	-	-	-	-	-	-	-	-	1,447.0	7,106.0
26	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	(12,369.0)	33,287.0
27	Investment Tax Credit Adjustment - Net	-	-	-	-	-	-	-	-	-	-	-	(573.0)
28	**Total Operating Expenses**	$0.0	$0.0	($1,030.0)	($14.0)	($3,225.0)	($1,035.0)	($2.0)	$33.0	($446.0)	($72.0)	($29,270.0)	$190,146.0
29	Revenue Requirement for Individual Columns	($417.0)	$3.0	($1,030.0)	($14.0)	($3,225.0)	($1,035.0)	($2.0)	$33.0	($446.0)	($72.0)	($18,193.0)	$300,386.0 (1)

(1) Line 29, Column 36 is different from Revenue Requirement on IP Exhibit 3.25, page 1, Line 10, by $956,000. This difference is the ITC amortizaiton of $573,000 times the gross-up conversion factor of 1.66431. This adjustment is included on IP Exhibit 3.25, page1, Lines 4a through 7.

Illinois Power Company
Calculation of Delivery Services Revenue Requirement
(Thousands of Dollars)

Line No. (1)	Component (2)	Revenue Requirement Calculation (3)
1	Net Rate Base 1/	$909,163
2	Times Before-Tax Weighted Cost of Capital 2/	8.92%
3	Return Requirement	$81,097
4	Income Tax Savings on Interest Synchronization Deduction 3/	(15,205)
4a	Amortization of Investment Tax Credits (ITC) 6/	(573)
5	After-tax Rate Base Return Requirement (Line 3 plus Line 4 and Line 4a)	$65,319
6	Times Gross-up Conversion Factor 4/	1.66431
7	Requested Return Grossed Up for Income Taxes	$108,711
8	Operating Expenses before Income Taxes but Including ITC 5/	$190,146
8a	Less: Amortization of Investment Tax Credits 6/	(573)
9	Operating Expenses before Income Taxes	$190,719
10	Revenue Requirement	$299,430

1/ IP Exhibit 3.24, Page 3, Line 17, Col. (36)
2/ IP Exhibit 3.18
3/ IP Exhibit 3.25, Page 2, Line 6
4/ Effective Federal income tax rate is 32.354%
Effective State income tax rate is 7.151%
Uncollectible adjustment rate is .41%
Combined effective income tax rate is 39.915%
Gross-up conversion factor =
1 / ((1 less Uncollectibes) - Tax Rate) = (1 / (1-.0041 - .39505)) = 1.66431
5/ IP Exhibit 3.24, Page 3, Line 28, Col. (36)
6/ IP Exhibit 3.24, Line 27

ILLINOIS POWER COMPANY
Interest Synchronization
(000s)

Line No.	Description	Tax Rate	Amount
	(1)	(2)	(3)
1	Original Cost Net Rate Base 1/		$909,163
2	Weighted Cost of Debt 2/		4.19%
3	Synchronized Interest		$38,094
4	Federal Income Tax Savings	32.354%	12,325
	Uncollectible Savings	0.41%	156
5	State Income Tax Savings	7.151%	2,724
	Total Tax Impact	39.915%	
6	Total Income Tax Savings		15,205

1/ IP Exhibit 3.24, Page 3, Line 17, Col. 136

2/ Long-Term Debt	2.41%
Transitional Funding Instruments	1.31%
Short-Term Debt	0.21%
Preferred Securities, Tax Advantaged	0.26%
	4.19%